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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)	
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005
And Related Matters.	Application 15-07-007 Application 15-07-008

ASSIGNED COMMISSIONER'S RULING ON THE ADOPTION OF DISTRIBUTED ENERGY RESOURCES GROWTH SCENARIOS

Summary

This Assigned Commissioner's Ruling (ACR) provides the investor-owned utilities (IOUs) with direction on application of the distributed energy resources (DER) growth scenarios for their 2017-18 planning cycle[1], and defines the issues

[1] The IOUs annual distribution planning process must commence after the summer peak in September with some variation by individual IOU.

and process for establishing system-level and locational disaggregation methodologies to be decided in the Track 3 decision. In sum, for the 2017-2018 cycle, the IOUs are directed to use:

1. The adopted 2016 IEPR demand forecast update, with limited adjustments to PV and EV forecasts, and
2. Their individual IOU-proposed methods to locationally disaggregate the data.

In order to timely plan for their 2018 summer peak grid needs, the IOUs require immediate guidance on the planning assumptions they should use beginning in September 2017.

1. Background

The DER Growth scenarios are a set of forecasts used as the planning assumptions to determine the grid needs for distribution resource planning, in order to meet the requirements of Public Utility Code 769. The legislation requires each IOU to: (1) identify "optimal" locations for the deployment of DERs; (2) submit DRPs that, once approved, must minimize overall system costs and maximize ratepayer benefit from investments in DERs; (3) identify any additional utility spending necessary to integrate cost-effective DERs into distribution planning consistent with the goal of yielding net benefits to ratepayers; and (4) propose any spending on distribution infrastructure necessary to accomplish the DRP in its GRC. Spending may be approved if ratepayers would realize net benefits and costs are just and reasonable. The level of investment on integration of DERs approved through this process depends on the assumed forecast of load and DER growth.

The DER growth scenarios established in this proceeding will also set the planning assumptions by which the IOUs will determine grid needs for grid modernization and distribution deferral. Effective DRP policy should minimize the cost to integrate DERs, and maximize distribution investment deferrals with DERs providing grid services.

In the current practice of distribution planning, the IOUs use the forecasts they develop internally to support a variety of processes, including the General Rate Case, FERC Rate Case, and as a submission to CEC to inform the California Energy Demand (CED) forecast in the Integrated Energy Policy Report (IEPR).

The utilities' Long Term Procurement Plan (LTPP) need determinations, as well as the California Independent Systems Operator (CAISO) Transmission Planning Process (TPP), are based on IEPR demand forecast. At the beginning of each biennial IEPR cycle, the IOUs submit their load and DER forecasts to the CEC. The CEC uses that information to inform its own forecast development, vets their forecast with stakeholders, and produces a final adopted forecast in January of even-numbered years. The CEC also does a limited update to its forecast in the off-year, which takes into account any changes in economic and demographic drivers, but does not reassess impacts of DER forecasts.

The application of IEPR demand forecast results to the IOUs' distribution resource planning is challenged by the current misalignment of their schedules—the full IEPR forecast is a biannual process conducted in odd-numbered years and adopted in beginning of every even-numbered year. For the 2017 IEPR, the CEC will release a preliminary forecast in early August, a revised forecast in October, and a final forecast in December for adoption in January 2018. Meanwhile, the IOU distribution planning process begins in the third quarter of each year. So, for example, the most recently adopted IEPR forecast is the 2016 Update, which uses DER forecast data from 2015. This indicates that the IOUs must either use IEPR forecasts from 2016 or use their own 2017 forecast submittals to the 2017 IEPR process, which are still in the process of being vetted by the CEC. This Ruling concludes that the 2016 adopted IEPR forecast mid-case is the best source for 2017 DRP Growth Scenarios trajectory case, but that the PV forecast may be adjusted to account for policy changes since 2015, including the extension of the ITC and NEM 2.0, and the EV forecast may be adjusted to account for the latest public data regard ZEV adoption and load growth. The IOUs should provide a justification and explanation of any adjustments they make to the 2016 IEPR DER forecasts.

2. Procedural Background

The IOUs submitted Distribution Resource Plans in July 1, 2015, which included their proposed approach to forecast DERs. The Scoping Memo on January 27, 2016 determined that the development of DER growth scenarios should be vetted within Track 3 of the DRP proceeding, considering its coordination with other procurement related proceedings, CEC's IEPR, and CAISO's TPP. The Energy Division initiated the stakeholder process with a workshop held on February 10, 2017, where the IOUs presented their plans for developing DER growth scenarios as well as a proposed review process. The Administrative Law Judge (ALJ) adopted this process via ruling on February 27.

The February 27, 2017 ALJ ruling provided guidance for the development of the growth scenarios to be developed consistent with IEPR forecast used in Integrated Resource Plan (IRP) and TPP, but stated that divergence from state-level assumptions may be necessary if there is better information available or unique circumstances in the application of state level assumptions to local planning processes and models. Early in the stakeholder process it was determined that, for 2017, the growth scenarios effort should focus exclusively on a trajectory case, particularly because the alternative (high/low) cases envisioned to come from the IRP process would not be finalized.

In response, the IOUs submitted a draft Assumptions and Framework document on April 7, 2017 and a revised document on June 9, 2017, following a series of working group meetings to vet their methodologies. 11 parties filed comments and replies in response to questions on the 2017 system-level forecast, locational disaggregation methods, and future updates to the growth scenarios. Overall, parties recognized that this was the first round in the process, and expected to see greater consistency and transparency in the future. A few parties recommended that growth scenarios should involve evaluation and clarification regard inputs such as load shapes.

3. Results & Outcomes from IOU Assumptions and Framework

In the joint utilities' Assumptions and Framework document, each IOU proposed their own set of source data to use for their 2017 system level DER growth forecasts (see table below). SCE and SDG&E propose to use their 2017 IEPR submittals. In their submittals, the IOUs present their forecast methodology for behind-the-meter distributed generation and electric vehicles, and propose to apply the Demand Response Load Impact Report for demand response, AAEE forecast for energy efficiency, and the AB 2514 targets for energy storage. SCE and SDG&E propose to align with the 2017 IEPR in order to provide the most updated information in the Distribution Planning Process, and to provide better quality disaggregation information for the 2018-19 TPP, which will also use the 2017 IEPR.

While PG&E also developed and presented their forecasting methodologies for DG and EVs, they propose to use the forecast from the 2016 IEPR Update. PG&E states that its existing practice is to align with the TPP of the current year, and they propose to continue to use the DER assumptions proposed by Commission staff for use in the 2017 LTPP studies, and specifically with CAISO's 2017-18 TPP process.

IOUs' Proposed Sources for DER Growth Scenario Forecasts

<table>
<tr><th></th><th>PG&E</th><th>SCE</th><th>SDG&E</th></tr>
<tr><td>DG (BTM)</td><td rowspan="4">2016 IEPR Update Mid Case</td><td>SCE 2017 IEPR submittal**</td><td>SDG&E 2017 IEPR submittal*</td></tr>
<tr><td>EE</td><td>2016 Low Mid AAEE (C&S), 2017 P&G Study (programs)*</td><td>2016 IEPR- Low Mid AAEE</td></tr>
<tr><td>DR (load modifying)</td><td>2017 DR Load Impact Report</td><td>2017 DR Load Impact Report</td></tr>
<tr><td>EV</td><td>SCE Latest Forecast</td><td>SDG&E 2017 IEPR submittal*</td></tr>
<tr><td>Storage</td><td colspan="3">Existing Storage + AB2514 Targets</td></tr>
</table>

The IOUs' framework document provided some explanation of their methodologies for PV and EVs, but was lacking in detail and inconsistent in the information that was provided.

For coordination with procurement and transmission planning, alignment with different planning years is problematic. For example, the Commission's IRP process is designed to determine the optimized level of DERs, and should, therefore, include an assessment of the associated grid integration costs and benefits. Defining the appropriate policy mechanism will depend on running sensitivities on the forecasting input assumptions, so it is necessary to have a common basis from which to begin.

In their comments, the IOUs state that the DRP is not well-positioned to assess the merits of any particular forecasting methodology. They point out that the DRP has not developed a record to support any particular forecasting approach, nor have forecasting experts necessarily attended DRP events.

I agree the DRP is not currently well-positioned to evaluate the merits of the IOU's various system-level forecast methodologies. In contrast, the CEC's IEPR process is structured to thoroughly vet forecasting issues of a technical, and sometimes contentious, nature. Further, it is prudent to strive towards consistency and transparency in planning assumptions, which the CEC's IEPR process provides. The IOUs' 2017 IEPR submittals, in fact, represent a range of divergence from the 2016 IEPR Update forecast, and these issues have not been sufficiently documented or vetted within this proceeding.

Therefore, I find that the most suitable and defensible forecast data available at this time is the 2016 adopted IEPR forecast update. While this forecast does not include some recent policy changes or updated market information, it has been thoroughly vetted by the CEC. If the IOUs find it necessary, they may make adjustments to the IEPR PV forecasts to reflect policy changes that have been adopted since the source data was developed for the 2016 forecast.[2] The EV forecast may be adjusted to account for the latest published data regarding ZEV adoption and load growth. The IOUs should provide a justification and explanation of any adjustments they make to the 2016 IEPR DER forecasts. The IOUs proposed application of their existing capacity plus the AB 2514 targets represent the most suitable data for energy storage.

I understand that the separate adjustments to the forecast may lead to inconsistencies in the IOU's DER growth scenarios; this guidance only applies to 2017, and I expect to see a consistent approach developed to update the forecast in the years in between the full IEPR. I will further discuss how to address future updates to the growth scenarios below.

[2] The 2016 IEPR demand forecast update is based on DER forecasts that were developed in the 2015 IEPR.

4. Approaches to Locational Disaggregation Methodologies for DER Growth Scenarios

The IOUs developed separate methodologies to disaggregate DER growth to the feeder level, stating that their methodology should be tailored to the unique characteristics of each IOU's distribution grid. Locational disaggregation involves the additional challenges of increased uncertainty at the feeder level. These challenges are particularly acute in this year of implementing the distribution resource planning process, when the disaggregation methodologies.

Locational disaggregation is particular to the characteristics of each IOU's distribution system, and determining the most reliable methodology to disaggregate the forecasts will be an evolving process. For their 2017 Growth Scenarios, the IOUs are directed to use their locational disaggregation methodologies as proposed by each IOU. It is expected that the IOUs will refine these methodologies in the future cycles by evaluating the outcomes of past forecasts and assessing and implementing best practices.

The IOUs are expected to further coordinate with CAISO to understand the potential operational issues at the transmission and distribution interface and how to coordinate on the busbar level disaggregation.

The process for review of updates to the locational disaggregation methodologies will be defined and clarified in the Track 3 decision dealing with Growth Scenarios for 2018 and beyond.

5. Plan for Future Updates to DER Growth Scenarios

In order to establish well-functioning update process for future DER growth scenarios based on the IEPR process, the Commission will need more information from CEC, CAISO, the IOUs, and parties. The DRP proceeding does not seek to replicate the work of CEC's IEPR forecast. However, the Commission needs to establish a framework for establishing a consistent and reliable forecast on an annual basis. Further work is needed to prepare for 2018 and beyond.

As a guiding principle, the system level forecast of the DER growth scenarios should be based on the most recent IEPR forecast, but there are critical timing considerations to work through. In the Track 3 decision, the Commission will need to determine how to update the DER growth scenarios in the off-years between the biennial full IEPR forecast. Updates may be necessary due to material changes in policy or market adoption rates. Yet, consistency with IEPR forecasting methods should be the goal. We understand that the CEC is conducting a limited update to its demand forecasts on an annual basis to accommodate the California ISO's transmission planning needs. The Commission aspires to a more robust update that specifically addresses the various DER resource types.

It may be valuable for the IOUs to develop refinements to load and DER forecasting methods as well as disaggregated input data, and to the extent possible, those should be brought into the IEPR forecast process. For example, what data about load and DER penetration can IOUs provide with minimal lag time that will enable the CEC to improve its regional disaggregation below IOU-dominated planning areas? In addition, IOU and stakeholders' ability to review IEPR forecasting models, inputs, and assumptions, and propose alternatives, should continue to be encouraged and facilitated through transparent processes. Towards that end, Energy Division staff is requested to work with CEC to consider whether, and if so, how, more effective engagement of IOUs and parties in the CEC's IEPR demand forecast process could be facilitated to assist the development of DER forecasts.

As noted previously, stakeholders agreed that the 2017 growth scenarios process should only consider the development of a trajectory case for DER growth that is most likely to occur given current policies and market adoption rates. For future updates, high and low case DER growth scenarios should also be developed based on the IRP Reference Plan. The Track 3 decision will consider how the high and low cases should be used in the Grid Needs Assessment.

6. Next Steps

For the 2018 and beyond planning cycles, the Track 3 decision will need to resolve the following issues:

System-level Forecast:

1. The process for updating the DER growth forecasts in the off-years, and what role the IOUs should play.
2. Improvements in underlying inputs to DER growth forecasts which may be necessary to assure that a more DER-inclusive off-year demand forecast is actually a worthwhile endeavor.
3. The possibility of CEC augmenting its existing annual demand forecast updates to include some (or all) DERs.
4. The possibility of CEC adjusting the timing of the release of its various iterations of its demand forecast (staff preliminary, staff revised, and CEC-adopted). Adjusting the CEC timing would require changes in the timing of work products that inform the demand forecast such as the CPUC's energy efficiency potential studies
5. Approaches to improved communication about forecasting models, inputs, and assumptions in the CEC's IEPR process, and whether common frameworks, assumption templates, or other tools are needed.
6. The role of the Growth Scenario Working group in vetting system level forecasts.

High and Low Case DER Growth Scenarios:

7. The approach to applying IRP scenarios for high and low DER growth scenarios.
8. How the high and low DER growth scenarios may be used in the Grid Needs Assessment.

Locational Disaggregation Methods:

9. Are all DER resources tracked to the circuit level in a timely manner and are rollups of such data to higher levels of aggregation being made available to distribution and transmission level planning processes?
10. How evaluation and calibration get incorporated into the locational disaggregation process to ensure that circuit level forecasts reflect accurate data and best modeling practices.
11. Issues that need to be considered for process alignment at the transmission and distribution interface.
12. The role of the Growth Scenario Working group and the Commission in vetting of the locational disaggregation.

In order to resolve these issues, I direct the Commission's Energy Division Staff to work with the CEC to submit a straw proposal for consideration by the Commission. The Energy Division may convene the Growth Scenario Working Group as needed to discuss these issues in preparation of comments.

If the IOUs plan to make adjustments to the 2016 PV or EV forecasts, they should submit these adjustments by Tier 1 advice letter within 60 days of this ruling.

IT IS SO RULED.

Dated August 9, 2017 at San Francisco, California.

/s/ MICHAEL PICKER
Michael Picker
Assigned Commissioner